TECHNICAL REVIEW AND EVALUATION
OF APPLICATION FOR
AIR QUALITY PERMIT NO. 1000102

I. INTRODUCTION

This operating permit is issued for the operation of Tucson Electric Power's Irvington Generating Station (IGS) which is located in Tucson at 3950 East Irvington Road, Tucson, AZ 85714. IGS generates electricity. This is accomplished by combustion of fuels. There are four steam turbine units and three gas turbine units at the station. The principal fuels used are coal and natural gas, with various units having the capacity to combust other fuels.

A. Company Information

Company Name:	Tucson Electric Power Company
Facility Name:	Irvington Generating Station
Mailing Address:	200 West Sixth Street, PO Box 711, Tucson, AZ 85702
Facility Address:	3950 East Irvington Road, Tucson, AZ 85714
Phone Number:	520-571-4000

B. Attainment Classification

IGS is located in an area designated as Non-Attainment for Carbon Monoxide. The procedure to redesignate this area as Attainment for this pollutant is currently underway.

II. PROCESS DESCRIPTION

A. Process Description

IGS generates electricity by two processes : (1) Steam Turbine Cycle, and (2) Gas Turbine Cycle.

<u>Steam Turbine Cycle</u>

There are three distinct units in this process : (1) Boiler, (2) Turbine, and (3) Generator.

(1) Boiler

In the boiler process water is converted to steam. This is accomplished by combustion of fuel and heat transfer to the water side. The products of combustion are conveyed to the ambient atmosphere. The type of pollutants released into the atmosphere depend on the kind of fuel fired. Typical pollutants are Particulate Matter (PM), Sulfur Dioxides (SO_2), Nitrogen Oxides (NOx), Carbon Monoxide (CO), and Volatile Organic Compounds (VOC). Pollutant emission rates specific to boilers at IGS are provided in Section III of this document.

(2) Turbine

The steam exiting from the boiler enters the turbine unit. The turbine unit consists of sets of stationary and rotating blades. The stationary blades are fixed to the turbine casing, and the rotating blades are fixed to a shaft. As the high pressure steam passes through the rotating blades, the blades move and this causes the turbine shaft to rotate. The stationary blades direct the steam on to the next set of rotating blades. In essence the turbine unit serves to convert the thermal energy of the steam into mechanical energy of the turbine shaft. The steam exits from the turbine unit and is sent through a condenser before being recirculated to the boiler. The only process material used at the turbine unit is steam. Therefore, there are no emissions of any regulated air pollutants at this location.

(3) Generator

In the generator mechanical energy is converted to electrical energy. There are no emissions at this locations.

Gas Turbine Cycle

In the Gas Turbine Cycle energy conversion is accomplished by two components : (1) Turbine, (2) Generator. Fuel and air are mixed and injected into a combustion chamber where they are ignited. The hot combustion gases pass over the turbine blades. The resulting movement of the blades causes the shaft to rotate. The shaft is connected to the generator shaft. Emissions resulting from combustion typically include PM, SO_2 , NOx, CO and VOC. Representative emission rates are provided in Section III.

Support Activities

The chief purpose of IGS is to generate electricity. In addition to the steam and gas turbines, there are a number of other supporting activities. Many of the support activities result in air emissions, and are subject to various air quality control regulations. The main support activities that result in significant air emissions are : (i) Auxiliary Boiler (PM, NOx, SO2, CO, VOC), (ii) Coal Handling System and Emergency Coal Storage Pile (PM), and (iii) Fly Ash Handling System (PM).

B. Process Rate and Operating Hours

IGS needs the flexibility to operate 24 hours a day, 365 days a year. The net capacities of the various units are as follows:

Irvington Station Steam Unit I1 : 81.02 MW
Irvington Station Steam Unit I2 : 80.53 MW
Irvington Station Steam Unit I3 : 104.45 MW
Irvington Station Steam Unit I4 : 156.1 MW

Irvington Station Gas Unit IGT1 : 23.9 MW
Irvington Station Gas Unit IGT2 : 24.5 MW
Irvington Station Gas Unit IGT3 : 24.7 MW

III. EMISSIONS

Representative emissions from IGS are presented in the following table. They may be used for the following purposes:

(i) Ascertaining "major source" status of IGS pursuant to CAA Sec 501 (2);
(ii) Comparing source potential-to-emit with emission rates allowable by relevant standards; and
(iii) Comparing source potential-to-emit with emissions inventory and test data.

This comparison serves as a summary of existing information on emissions from IGS. These emissions calculations are **not** meant to establish any baseline emissions levels. These emissions figures (except for the ALLOWABLE emissions) are **not** meant to be emissions limitations of any form. Table III.1 summarizes the potential to emit (PTE), allowable emissions, test results, and the emissions inventory (EI) data. The emission factors used to calculate the potential to emit are from AP-42 (1/95 ed.).

TABLE III.1 : Summary of Emissions Information

UNIT I1 BOILER					
Fuel	**Pollutant**	**PTE**	**Allowable†**	**EI (1996)**	**Test**
Natural Gas	PM	4 lb/hr (17.5 tpy)	172 lb/hr (= 753 tpy) [A.A.C.R18-2-703.C.1]	1.51 tpy	NA
	NOx	963.5 tpy	NA	45 tpy	NA
	SOx	2.1tpy	NA	0.2 tpy	NA
	CO	140 tpy	NA	12.12. tpy	NA
	VOC	6 tpy	NA	0.52 tpy	NA
	THAP★	1.84 tpy	NA	NA	NA
Liquid (#6 Fuel Oil)	PM	61 lb/hr (269 tpy)	172 lb/hr (= 753 tpy) [A.A.C.R18-2-703.C.1]	NA	NA
	NOx	982 tpy	NA	NA	NA
	SOx	3303 tpy	1 lb SO2/MBTU 3-hr avg. (= 3504 tpy) [A.A.C.R18-2-703.E.1]	NA	NA
	CO	117 tpy	NA	NA	NA
	VOC	18 tpy	NA	NA	NA
	THAP★	3.3 tpy	NA	NA	NA
Natural Gas w/ Supplemental Landfill Gas	PM	7 lb/hr (31 tpy)	172 lb/hr (= 753 tpy) [A.A.C.R18-2-703.C.1]	NA	NA
	NOx	963.5 tpy	NA	NA	NA
	SOx	15 tpy	NA	NA	NA
	CO	149 tpy	NA	NA	NA

Fuel	Pollutant	PTE	Allowable†	EI (1996)	Test
	VOC	6 tpy	NA	NA	NA
	THAP★	1.84 tpy	NA	NA	NA
Liquid (#6 Fuel Oil) w/ Supplemental Landfill Gas	PM	61 lb/hr (269 tpy)	172 lb/hr (= 753 tpy) [A.A.C.R18-2-703.C.1]	NA	NA
	NOx	982 tpy	NA	NA	NA
	SOx	3303 tpy	1 lb SO2/MBTU 3-hr avg. (= 3504 tpy) [A.A.C.R18-2-703.E.1]	NA	NA
	CO	117 tpy	NA	NA	NA
	VOC	18 tpy	NA	NA	NA
	THAP★	3.3 tpy	NA	NA	NA
UNIT I2 BOILER					
Fuel	**Pollutant**	**PTE**	**Allowable**	**EI (1996)**	**Test**
Natural Gas	PM	4 lb/hr (17.5 tpy)	172 lb/hr (= 753 tpy) [A.A.C.R18-2-703.C.1]	2.08 tpy	NA
	NOx	963.5 tpy	NA	75.70 tpy	NA
	SOx	2.1tpy	NA	0.30 tpy	NA
	CO	140 tpy	NA	16.66. tpy	NA
	VOC	6 tpy	NA	NA	NA
	THAP★	1.84 tpy	NA	NA	NA
Liquid (#6 Fuel Oil)	PM	61 lb/hr (269 tpy)	172 lb/hr (= 753 tpy) [A.A.C.R18-2-703.C.1]	NA	NA
	NOx	982 tpy	NA	NA	NA
	SOx	3303 tpy	1 lb SO2/MBTU 3-hr avg. (= 3504 tpy) [A.A.C.R18-2-703.E.1]	NA	NA
	CO	117 tpy	NA	NA	NA
	VOC	18 tpy	NA	NA	NA
	THAP★	3.3 tpy	NA	NA	NA
Natural Gas w/ Supplemental Landfill Gas	PM	7 lb/hr (31 tpy)	172 lb/hr (= 753 tpy) [A.A.C.R18-2-703.C.1]	NA	NA
	NOx	963.5 tpy	NA	NA	NA
	SOx	15 tpy	NA	NA	NA

Fuel	Pollutant	PTE	Allowable†	EI (1996)	Test
	CO	149 tpy	NA	NA	NA
	VOC	6 tpy	NA	NA	NA
	THAP★	1.84 tpy	NA	NA	NA
Liquid (#6 Fuel Oil) w/ Supplemental Landfill Gas	PM	61 lb/hr (269 tpy)	172 lb/hr (= 753 tpy) [A.A.C.R18-2-703.C.1]	NA	NA
	NOx	982 tpy	NA	NA	NA
	SOx	3303 tpy	1 lb SO2/MBTU 3-hr avg. (= 3504 tpy) [A.A.C.R18-2-703.E.1]	NA	NA
	CO	117 tpy	NA	NA	NA
	VOC	18 tpy	NA	NA	NA
	THAP★	3.3 tpy	NA	NA	NA
UNIT I3 BOILER					
Fuel	**Pollutant**	**PTE**	**Allowable**	**EI (1996)**	**Test**
Natural Gas	PM	5.2 lb/hr (23 tpy)	213 lb/hr (=933 tpy) [A.A.C.R18-2-703.C.1]	NA	NA
	NOx	1257 tpy	NA	NA	NA
	SOx	2.7tpy	NA	NA	NA
	CO	182 tpy	NA	NA	NA
	VOC	7.8 tpy	NA	NA	NA
	THAP★	2.37 tpy	NA	NA	NA
Liquid (#6 Fuel Oil)	PM	80 lb/hr (350 tpy)	213 lb/hr (=933 tpy) [A.A.C.R18-2-703.C.1]	NA	NA
	NOx	1280 tpy	NA	NA	NA
	SOx	4307 tpy	1 lb SO2/MBTU 3-hr avg. (= 4568 tpy) [A.A.C.R18-2-703.E.1]	NA	NA
	CO	152 tpy	NA	NA	NA
	VOC	23 tpy	NA	NA	NA
	THAP★	4.3 tpy	NA	NA	NA
UNIT I4 BOILER					
Fuel	**Pollutant**	**PTE**	**Allowable**	**EI (1996)**	**Test**

Fuel	Pollutant	PTE	Allowable†	EI (1996)	Test
Natural Gas	PM	8.5 lb/hr (37 tpy)	311 lb/hr (=1362 tpy) [A.A.C.R18-2-703.C.1]	NA	NA
	NOx	2050 tpy	0.7 lb NO2/MBTU 3-hr avg. (= 5218 tpy) [IP 1156]	NA	NA
	SOx	4.5 tpy	1 lb SO2/MBTU 3-hr avg. (= 7455 tpy) [IP 1156]	NA	NA
	CO	298 tpy	NA	NA	NA
	VOC	13 tpy	NA	NA	NA
	THAP★	3.85 tpy	NA	NA	NA
Liquid (#6 Fuel Oil)	PM	130 lb/hr (350 tpy)	311 lb/hr (=1362 tpy) [A.A.C.R18-2-703.C.1]	NA	NA
	NOx	2090 tpy	0.7 lb NO2/MBTU 3-hr avg. (= 5218 tpy) [IP 1156]	NA	NA
	SOx	7029 tpy	1 lb SO2/MBTU 3-hr avg. (= 7455 tpy) [A.A.C.R18-2-703.E.1]	NA	NA
	CO	249 tpy	NA	NA	NA
	VOC	35 tpy	NA	NA	NA
	THAP★	7 tpy	NA	NA	NA
Solid	PM	W/out Baghouse 8273 lb/hr (36235 tpy) W/ Baghouse (99.5%) 41.4 lb/hr (181 tpy)	223 lb/hr (=977 tpy) [A.A.C. R 18-2-703.C.1]	17.79 tpy	20.16 lb/hr [1997]
	NOx	3866 tpy†	0.7 lb NO2/MBTU 3hr avg. (= 3382 tpy) [IP 1156]	2111 tpy	0.70 lb NO2/MBTU [1997]
	SOx	5099 tpy†	1.0 lb SO2/MBTU 3 hr avg. (= 4831 tpy) [IP 1156]	2225 tpy	0.694 lb SO2/MBTU [1997]
	CO	134 tpy	NA	70.52 tpy	NA
	VOC	16 tpy	NA	14.10 tpy	NA
	THAP★	65.7 tpy	NA	NA	NA
Units I1D and I2D (emissions/unit): Cooling Towers for Unit I1 and Unit I2 Boilers					

Fuel	Pollutant	PTE	Allowable†	EI (1996)	Test
Fuel	**Pollutant**	**PTE**	**Allowable**	**EI (1996)**	**Test**
	PM	8.35 lb/hr (36 tpy)	108 lb/hr (474 tpy) [A.A.C.R18-2-730.A.1.b]	NA	NA
Unit I3D : Cooling Tower for Unit I3 Boiler					
Fuel	**Pollutant**	**PTE**	**Allowable**	**EI (1996)**	**Test**
	PM	11.6 lb/hr (51 tpy)	114 lb/hr (497 tpy) [A.A.C.R18-2-730.A.1.b]	NA	NA
Unit I4D : Cooling Tower for Unit I4 Boiler					
	PM	16 lb/hr (69 tpy)	119 lb/hr (521 tpy) [A.A.C.R18-2-730.A.1.b]	NA	NA
IAUX : Auxiliary Boiler					
Fuel	**Pollutant**	**PTE**	**Allowable**	**EI (1996)**	**Test**
Natural Gas	PM	2 tpy	28 lb/hr (=125 tpy) [A.A.C. R 18-2-724.C.1]	NA	NA
	NOx	44 tpy	NA	NA	NA
	SOx	0.18 tpy	NA	NA	NA
	CO	11.4 tpy	NA	NA	NA
	VOC	1.8 tpy	NA	NA	NA
	THAP★	0.17 tpy	NA	NA	NA
Liquid (#2 Distillate)	PM	4 tpy	28 lb/hr [A.A.C. R 18-2-724.C.1]	NA	NA
	NOx	48 tpy	NA	NA	NA
	SOx	131 tpy	1 lb SO2/MBTU heat input (= 320 tpy) [A.A.C.R18-2-724.E]	NA	NA
	CO	12 tpy	NA	NA	NA
	VOC	0.61 tpy	NA	NA	NA
	THAP★	0.15 tpy	NA	NA	NA
Units IGT1, IGT2, IGT3: Gas Turbines (Emissions/unit)					

Fuel	Pollutant	PTE	Allowable†	EI (1996)	Test
Natural Gas	PM	34 tpy	103 lb/hr (=450 tpy) [A.A.C. R 18-2-719.C.1]	0.32	NA
	NOx	771 tpy	NA	8.13	NA
	SOx	1.01 tpy	NA	0.01	NA
	CO	192 tpy	NA	2.09	NA
	VOC	42 tpy	NA	0.46	NA
	THAP★	0.7 tpy	NA	NA	NA
Liquid (#2 Distillate)	PM	66 tpy	103 lb/hr (=450 tpy) [A.A.C. R 18-2-719.C.1]	NA	NA
	NOx	1196 tpy	NA	NA	NA
	SOx	692 tpy	1 lb/MBTU (=1712 tpy) [A.A.C. R18-2-719.F]	NA	NA
	CO	83 tpy	NA	NA	NA
	VOC	29 tpy	NA	NA	NA
	THAP★	5 tpy	NA	NA	NA
Units IGT1A, IGT2A, IGT3A : Gas Turbine Diesel Starter Engines					
Diesel	PM	0.02 tpy	103 lb/hr (=450 tpy) [A.A.C. R 18-2-719.C.1]	NA	NA
	NOx	1.1 tpy	NA	NA	NA
	SOx	0.02 tpy	1 lb/MBTU Heat Input (= 7 tpy) [A.A.C.R18-2-719.F]	NA	NA
	CO	0.01 tpy	NA	NA	NA
	VOC	0.03 tpy	NA	NA	NA
	THAP★	1.7e-4 tpy	NA	NA	NA
Support Equipment Cumulative Emissions(Units I1B, I1C, I1D, I2B, I2C, I3B,, I3C, I4B, I4C, I4D, IGT1B, IGT2B, IGT3B)					
	TOC	168 tpy	NA	NA	NA
Coal Handling System					

Fuel	Pollutant	PTE	Allowable†	EI (1996)	Test
	PM-10	W/out Control 10,615 lb/hr (= 46, 493 tpy) W/Control (99.5%) 53 lb/hr (=232 tpy)	62 lb/hr (=272 tpy) [PCC 17.16.310.B.2]	28.63 tpy	NA
Fly Ash Handling					
	PM-10	W/out Control 5400 lb/hr (=23,652tpy) W/ control (99.5%) 27 lb/hr (=119 tpy)	65 lb/hr (=285 tpy)	0.96 tpy	NA

† : Most allowable emissions limits are in units of lb/hr. Where necessary, an assumption of 8760 hours of operation/year was made to calculate allowable emissions limits in tons per year (tpy).

★: Currently Hazardous Air Pollutants are not "regulated" for this source. There are no applicable requirements for this source category at this time.

: Unit I3 is presently a "peaking unit" with low actual emissions.

†: The PTE is larger than the allowable emissions rate. However, test data indicates that the unit is able to operate in compliance with the standard. Futhermore, Continuous Emission Monior (CEM) data indicate that there have been only four cases of exceedance of the NOx limits (see Table IV.B.1) since the year 1991. Emissions Inventory data indicate that actual emissions are below allowable emission limits.

Fuels:

Unit	Normal Operating Scenarios	Alternate Operating Scenarios
Unit I1 and Unit I2 Boilers	Natural Gas	
		Fuel Oil (#2 through #6)
		Co-firing Natural Gas and Fuel Oil (#2 through #6)
		Co-firing Natural Gas and Landfill Gas
		Co-firing Fuel Oil (#2 through #6) and Landfill Gas
		Co-firing Fuel Oil (#2 through #6) and Natural Gas and Landfill Gas
Unit I3 Boiler	Natural Gas	
		Fuel Oil (#2 through #6)

Unit	Normal Operating Scenarios	Alternate Operating Scenarios
		Co-firing Natural Gas and Fuel Oil (#2 through #6)
Unit I4 Boiler	Coal	
		Natural Gas
		Fuel Oil (#2 through #6)
		Co-firing Natural Gas and Fuel Oil (#2 through #6)
		Co-firing Natural Gas and Coal
		Co-firing Coal and Landfill Gas
		Co-firing Natural Gas and Landfill Gas
		Co-firing Fuel Oil (#2 through #6) and Landfill Gas
		Co-firing Natural Gas and Coal and Landfill Gas
		Co-firng Natural Gas and Fuel Oil (#2 through #6) and Landfill Gas
Unit IGT1, IGT2 and IGT3	Natural Gas	
		#2 Fuel Oil
		Co-firing Natural Gas and #2 Fuel Oil
Unit IAUX	Natural Gas	
		#2 Fuel Oil
		Co-firing Natural Gas and #2 Fuel Oil

In addition to the permitted fuels, the Title V application contains a request to burn landfill gas in Units I1, I2 and I4 boilers. As this fuel is derived from municipal solid waste, this does not constitute a "physical change or change in the method of operation" [AAC R18-2-101.60(c)(iv)].

IV. COMPLIANCE HISTORY

A. Inspections

Inspections are being regularly conducted on this source to ensure compliance with the permit conditions. Table IV.A.1 summarizes some of the recent inspections that have been conducted on the source and the results of the inspections.

TABLE IV.A.1 : Inspection Results

Inspection Date	Type of Inspection	Results
A.D.E.Q.		
6/25/97	Performance Test on Unit 4	Pass
6/21/96	Performance Test on Unit 4	Pass

Inspection Date	Type of Inspection	Results
12/5/95	Performance Test on Unit 4	Pass
12/8/95	Performance Test on Unit 4	Pass
12/20/94	Performance Test on Unit 4	Pass
11/16/94	Performance Test on Unit 4	Pass
9/29/94	Complaint investigation	Rectified
12/13/93	Performance Test on Unit 4	Pass
Pima County		
6/28/93	Annual pre-renewal inspection	Pass
7/29/92	Annual pre-renewal inspection	Pass
7/3/91	Annual pre-renewal inspection	Pass
6/21/90	Annual pre-renewal inspection	Pass
6/21/89	Annual pre-renewal inspection	Pass
7/5/88	Annual pre-renewal inspection	Pass
7/7/87	Annual pre-renewal inspection	Pass
6/23/86	Annual pre-renewal inspection	Pass
7/10/84	Annual pre-renewal inspection	Pass
7/7/83	Annual pre-renewal inspection	Pass

B. Excess Emissions

A summary of the excess emissions reported over the past few years is presented in Table IV.B.1.

TABLE IV.B.1 : Summary of excess emissions

Date Reported	Source	Pollutant	Cause
3/14/97	Unit I4	NOx	High air flow. 3 hours. 0.76 lb/MMBTU max.
11/1/96	Unit I4	NOx	Air flow monitor failure. 3 hrs. 0.94 lb/MMBTU max.
11/16/95	Unit I4	Opacity	Baghouse controller failure. 30 min. 75% max.
11/18/95	Unit I4	Opacity	Baghouse controller failure. 10 min. 56 % max.

Date Reported	Source	Pollutant	Cause
7/28/95	Unit I4	Opacity	Baghouse controller failure. 10 min. 50 % max. Baghouse controller failure. 10 min. 31 % max.
8/10/95	Unit I4	Opacity	Baghouse controller failure. 30 min. 100 % max.
4/2/95	Unit I4	Opacity	ID fan disturbed ash in duct. 30 min. 71% max.
3/5/95	Unit I4	Opacity	On fan start dust in ductwork disturbed. 6 min. 28% max.
3/5/95	Unit I4	Opacity	On fan start dust in ductwork disturbed. 6 min. 30% max
3/15/95	Unit I4	Opacity	Baghouse controller failure. 25 min. 56% max.
3/29/95	Unit I4	Opacity	Baghouse controller failure. 12 min. 93% max.
11/94	Unit I4	Opacity	10 incidents. About 10 min. each. 95% max.
9/13/94	Unit I4	Opacity	Baghouse bypass dampers open. 30 min. 74% max.
9/27/94	Unit I4	Opacity	Baghouse inlet closed. 12 min. 42% max.
2/12/94	Unit I4	Opacity	Loose filter bag. 6 min. 29% max.
3/8/94	Unit I4	Opacity	Leaking filter bag. 6 min. 21% max.
5/25/93	Unit I4	NOx	Middle, upper burner elevations in service. 3 hrs. 0.8 lb/MMBTU max.
5/20/93	Unit I4	Opacity	2 incidents. Ash release. 6 min. each. 28% max.
1/14/93	Unit I4	NOx	Load change. 4 hrs. 0.8 lb/MMBTU max.
1/18/93	Unit I4	Opacity	Baghouse controller failure. 24 min. 50 % max.
6/6/91	Unit I4	Opacity	2 incidents. 10 min. each. 23% max.

C. Testing

The results of all the compliance tests have been summarized in Table IV.C.1. Results show that the units are in compliance with the applicable standards.

Date of Test	Equipment Tested	Pollutants Tested	Results
11/19/94	Unit I4	SO_2 NOx	Pass (0.792 lb/MMBtu vs. 1.0 lb/MMBtu) Pass (0.69 lb/MMBtu vs. 0.7 lb/MMBtu)
12/20/94	Unit I4	PM	Pass (34.33 lb/hr vs. 260 lb/hr)

Date of Test	Equipment Tested	Pollutants Tested	Results
12/8/95	Unit I4	PM SO_2 NOx	Pass (24.40 lb/hr vs. 218.13 lb/hr) Pass (0.825 lb/MMBtu vs. 1.0 lb/MMBtu) Pass (0.69 lb/MMBtu vs. 0.7 lb/MMBtu)
6/21-6/22/96	Unit I4	PM SO_2 NOx	Pass (5.97 lb/hr vs. 203.00 lb/hr) Pass (0.733 lb/MMBtu vs. 1.0 lb/MMBtu) Pass (0.68 lb/MMBtu vs. 0.7 lb/MMBtu)
6/25/97	Unit I4	PM SO_2 NOx	Pass (20.16 lb/hr vs. 234.90 lb/hr) Pass (0.694 lb/MMBtu vs. 1.0 lb/MMBtu) Pass (0.70 lb/MMBtu vs. 0.7 lb/MMBtu)

V. APPLICABLE REGULATIONS VERIFICATION

The Permittee has identified the applicable regulations that apply to each unit in the permit application. Table V.1 summarizes the findings of the Department with respect to applicability or non-applicability of applicable regulations that apply to each unit. Installation Permit and other previous permit conditions are discussed under Section VI of this technical review document.

TABLE V.1 : Applicable regulations verification

Unit ID	Start-up date	Control Equipment	Applicable Regulations	Verification
Units I1, I2, and I3 Boilers	I1 :1957 I2 : 1959 I3: 1961	None	A.A.C. R18-2-702.B A.A.C. R18-2-703.B A.A.C. R18-2-703.C.1 A.A.C. R18-2-703.E.1 A.A.C. R18-2-703.H A.A.C. R18-2-703.J A.A.C. R18-2-703.K PCC 17.16.160.B** PCC 17.16.160.C.1 PCC 17.16.160.D.1 PCC 17.16.160.G PCC 17.16.160.I PCC 17.16.160.J CAA Title IV	The installation date of these units predates the enactment of the Act. Since the heat inputs are in the range of 800 MMBtu/hr (>250 MMBtu/hr), these units are subject to AAC R18-2-703. NOx standards are not applicable to these units because the start-up date is prior to May 30, 1972. For the same reason, the SOx standard of 1.0 lb/MMBtu applies.

Unit ID	Start-up date	Control Equipment	Applicable Regulations	Verification
Unit I4 Boiler	1964	Baghouse	PCC 17.16.160 Installation Permit #1156 A.A.C. R18-2-702.B A.A.C. R18-2-703.B A.A.C. R18-2-703.C.1 A.A.C. R18-2-703.E.1 A.A.C. R18-2-703.H A.A.C. R18-2-703.J A.A.C. R18-2-703.K CAA Title IV	This unit was installed in 1964 and was burning natural gas and fuel oil till the '80s. In response to a mandatory coal conversion rule from the Department of Energy, this boiler was modified to also burn coal. Installation Permit #1156 was issued to cover the conversion. The conditions in the Installation Permit were transferred to Operating Permit #0375-96 ## Installation permit conditions are all more stringent than State Rules. Therefore, only IP conditions were cited in the permit.
Units IGT1, IGT2, IGT 3 : Gas Turbines	IGT 1: 1972 IGT2 : 1972 IGT3 : 1973	None	A.A.C. R18-2-719.A A.A.C. R18-2-719.B A.A.C. R18-2-719.C.1 A.A.C. R18-2-719.E A.A.C. R18-2-719.F A.A.C. R18-2-719.H A.A.C. R18-2-719.I A.A.C. R18-2-719.J A.A.C. R18-2-719.K PCC 17.16.340.B PCC 17.16.340.C.1 PCC 17.16.340.D PCC 17.16.340.E PCC 17.16.340.F PCC 17.16.340.I PCC 17.16.340.J	The installation dates of these units are prior to October 3, 1977, and hence are not subject to 40 CFR 60, Subpart GG. These units are subject to an opacity standard of 40% and sulfur dioxide standard of 1.0 lb/MMBtu when burning liquid fuel.
Unit IAUX: Auxiliary Boiler	NA	None	A.A.C. R18-2-724.B A.A.C. R18-2-724.C.1 A.A.C. R18-2-724.E A.A.C. R18-2-724.G A.A.C. R18-2-724.J PCC 17.16.165.B PCC 17.16.165.C.1 PCC 17.16.165.D PCC 17.16.165.E PCC 17.16.165.G PCC 17.16.165.J	Heat input is 73 MBTU/hr (< 250MBTU/hr)

Unit ID	Start-up date	Control Equipment	Applicable Regulations	Verification
Units IGT1A, IGT2A, IGT3A : Turbine Starter engines	NA	None	A.A.C. R18-2-719.A A.A.C. R18-2-719.B A.A.C. R18-2-719.C.1 A.A.C. R18-2-719.E A.A.C. R18-2-719.F A.A.C. R18-2-719.H A.A.C. R18-2-719.I A.A.C. R18-2-719.J A.A.C. R18-2-719.K PCC 17.16.340.B PCC 17.16.340.C.1 PCC 17.16.340.D PCC 17.16.340.E PCC 17.16.340.F PCC 17.16.340.I PCC 17.16.340.J	Internal Combustion Engines
Allied Signal Microturbine	2/1998	None	A.A.C. R18-2-719.C.1 A.A.C.R18-2-719.E	Internal Combustion Engine
Coal Handling	NA	Enclosures, Spray Bars, Baghouses	IP #1156 A.A.C. R18-2-702.B A.A.C. R18-2-716.B.2 AZ SIP R9-2-516.A.2.b A.A.C. R18-2-716.D A.A.C. R18-2-716.E PCC 17.16.310.B.2 PCC 17.16.310.D PCC 17.16.310.E	Added at time of Unit I4 coal conversion project.[##]
Fly Ash handling	NA	Baghouses	IP # 1156 A.A.C. R18-2-702.B A.A.C. R18-2-730.A.1 A.A.C. R18-2-730.B PCC 17.16.430.A.1.a PCC 17.16.430.B PCC 17.16.430.D	Added at time of Unit I4 coal conversion.
I1E, I2D, I3D, I4E : Cooling Towers	1957, 1959, 1961, 1964	None	A.A.C. R18-2-702.B A.A.C. R18-2-730.A.1.b A.A.C. R18-2-730.D A.A.C. R18-2-730.G	Particulate emissions
Generator and Turbine Accessories	NA	None	A.A.C.R18-2-730.D PCC 17.16.430.D	VOC emissions

Unit ID	Start-up date	Control Equipment	Applicable Regulations	Verification
Hot water and Space Heaters	misc.	None	A.A.C. R18-2-724.B A.A.C. R18-2-724.C.1 A.A.C. R18-2-724.E A.A.C. R18-2-724.G A.A.C. R18-2-724.J	This is a collection of small combustion sources (capacities in the range of 100kBtu). There are a large number of such units. The capacities add up to larger than 500,000 Btu
Non-point sources	NA	Paving, water etc.	OP #375-96, II.B A.A.C. R18-2-604.A A.A.C. R18-2-605 A.A.C. R18-2-606 A.A.C. R18-2-607 A.A.C. R18-2-804.B PCC 17.16.050 Pima SIP Rule 343 PCC 17.16.070.A PCC 17.16.080 PCC 17.16.090.A PCC 17.16.090.B Pima SIP 315(F) PCC 17.16.090.D PCC 17.16.090.F PCC 17.16.090.G PCC 17.16.100.C PCC 17.16.110	These regulations regulate dust emissions from open areas, roads, storage piles and other such open non-point sources.
Abrasive Blasting	NA	Enclosures etc.	AAC R18-2-726 PCC 17.16.100.E	These rules are applicable to all abrasive blasting operations
Spray Painting	NA	Enclosures etc.	AAC R18-2-702.B AAC R18-2-727.A AAC R18-2-727.B AAC R18-2-727.C AAC R18-2-727.D SIP R9-3-527.C	These rules are applicable to spray painting operations.
Mobile Sources	NA	NA	AAC R18-2-801 AAC R18-2-802 AAC R18-2-804.A PCC 17.16.440 PCC 17.16.450 PCC 17.16.470	These rules are applicable to mobile sources.
Demolition/Renovation	NA	NA	AAC R18-2-1101.A.8	These rules are applicable to asbestos removal operations.
Nonvehicle AC	NA	NA	40 CFR Part 82	-

** PCC stands for Pima County Code. The source is located in Pima County, therefore Pima County Code Title 17 regulations are also applicable. These regulations are identical with the State rule (AAC Title 18, Chapter 2) in most cases. A comparison between these sets of rules is presented in Table V.2. In the permit document only the State rule is cited where possible (i.e, when State rule is at least as stringent as County rule) in an effort to “streamline” the permit. The Pima County rules are included in the permit shield (see Attachment C of the permit).

Note on Unit I4 : Unit I4 (manufactured in 1964) was originally designed to fire natural gas and oil. This was permitted by Pima County till the early ‘80s. In 1980 the Department of Energy promulgated regulations that required certain large power plants to convert their operations to burn coal. TEP applied for an installation permit for the coal conversion project. Although the initial plan was to convert all four units, only Unit I4 was converted. Since this change was mandated by a government order, NSR requirements are not applicable [AAC R18-2-101(60)(c)(ii)]. The NSPS definition for “modification” also exempts mandatory coal conversion projects [40 CFR 60.14(e)(4) and CAA Sec 111(a)(8)]. Therefore, NSPS(Subpart D) requirements are not applicable to Unit I4. As the coal preparation plant was constructed as part of the coal conversion project, NSPS requirements are not applicable to the coal preparation plant.

TABLE V.2 : Comparison of Pima County Code Title 17 and Arizona Administrative Code Title 18, Chapter 2 regulations

PCC Title 17	AAC Title 18, Chapter 2	Equivalence
17.16.020.B	18-2-730.G	Identical *(This means that the language of the two rules are exactly the same)*
17.16.040	18-2-702.B, 18-2-702.C	Equivalent *(This means that even though the language is not exactly the same, the two rules are equally stringent)*
17.16.050	None	PCC more stringent. Included in permit. [Attachment B, Sub-Paragraph I.K.1.b]
17.16.070.A	18-2-604.B	Identical
17.16.080.A 17.16.080.B 17.16.080.C	18-2-604.A	Equivalent
17.16.090.A 17.16.090.B 17.16.090.D	18-2-605.A 18-2-605.B	Equivalent
17.16.090.F	None	PCC more stringent. Included in permit. [Attachment B, Paragraph I.K.3]
17.16.100.C	18-2-605.B	Equivalent
17.16.100.D	None	PCC more stringent. Included in permit. [Attachment B, Sub-Paragraph I.L.5.c]
17.16.100.E	18-2-726	AAC more stringent
17.16.110.A	18-2-607.A	Identical
17.16.110.B	18-2-607.B	Equivalent
17.16.130.C	18-2-702.B	Identical

PCC Title 17	AAC Title 18, Chapter 2	Equivalence
17.16.160.B	18-2-703.B	Identical
17.16.160.C.1	18-2-703.C.1	Identical
17.16.160.D.1	18-2-703.E.1	Identical
17.16.160.F	18-2-703.G.1	Identical
17.16.160.G	18-2-703.H	Identical
17.16.160.H.3	18-2-703.I.3	Identical
17.16.165.B	18-2-724.B	Identical
17.16.165.C.1, .D	18-2-724.C.1, .D	Equivalent
17.16.165.E	18-2-724.E	Identical
17.16.165.G	18-2-724.G	Identical
17.16.165.J	18-2-724.J	Identical
17.16.310.B.2	18-2-716.B.2	In this case, P=3000 tons/hour. PCC is more stringent (62 lb/hr vs 93 lb.hr). PCC rule in permit. Paragraph I.G.2 of permit.
17.16.310.D	18-2-716.D	Identical
17.16.310.E	18-2-716.E	Identical (also see comparison for PCC 17.16.070 - 17.16.110)
17.16.340.B	18-2-719.B	Identical
17.16.340.C.1, .D	18-2-719.C.1, .D	Equivalent
17.16.340.E	18-2-719.E	Identical
17.16.340.F	18-2-719.F	Identical
17.16.340.I	18-2-719.I	Identical
17.16.340.J	18-2-719.J	Identical
17.16.430.A.1.a	18-2-730.A.1.a	Identical
17.16.430.B	18-2-730.B	Identical
17.16.430.D	18-2-730.D	Identical
17.16.440.B	18-2-801.B	Identical
17.16.450	18-2-802	Identical
17.16.470	18-2-804	Identical

PCC Title 17	AAC Title 18, Chapter 2	Equivalence
17.16.540	None	PCC more stringent. Included in permit. [Attachment B, Sub-Paragraph I.L.5.b]

TABLE V.3 : Comparison between Pima County Applicable SIP and Pima County Code, Title 17
(Column 1 lists only those SIP requirements that are applicable to IGS)

Pima County Applicable SIP, Chapter III	Pima County Code, Title 17	Equivalence
Rule 315	17.16.090	Equivalent (Language not same, but stringency of pollutant specific standard is same)
Rule 316	17.16.100	Equivalent
Rule 318	17.16.080	Equivalent
Rul3 321	17.16.040	Equivalent
Ruke 332	17.16.060 17.16.165 17.16.310 17.16.430	Equivalent
Rule 343	17.16.050	Equivalent
Rule 344	17.16.030	Equivalent

VI. PREVIOUS PERMITS AND CONDITIONS

A. Previous Permits

Table VI.A below lists all the permits that have been issued to the source thus far.

TABLE VI.A : Previous permits

Date Permit Issued	Permit #	Application Basis
The effective date of this permit is the date the initial Title V permit is issued, or 1/1/2000 whichever is earlier	1000663	Significant Revision to #0375-96 (Title IV requirements)
6/11/1998	1000750	Addition of Microturbine
2/8/1993	0375-96	Operating Permit
10/14//1981	1156	Installation Permit
< 1981	PCDEQ 1052	Operating Permit

B. Previous Permit Conditions

Table VI.B crossreferences the previous permit conditions with their location in the proposed Title V permit. Brief discussions provide reasons for apparent reductions in stringency. Copies of IP #1156 and OP #0375-96 are attached to this technical review document.

TABLE VI.B : Previous permits

IP #1156 references	Operating Permit #0375-96 references	Title V #1000102, Attachment B references
1	NA	NA
2	NA	NA
3	VII.C	II.B.5
4	VII.A, II.A	I.B.3.c.(2), I.B.3.a, I.B.3.b, I.B.3.c.(1)
5	II.A; II.B	I.B.1, I.B.3, I.B.4,I.B.6, I.J.4, I.K.1
6	V.A, V.C, II.C, V.B	III.B.1, III.B.3, III.B.6
7	VIII.A	II.B, II.C
8	VIII.E	II.A, II.C.1
9	NA	NA
10	VIII.B	II.C.2
11	VIII.C	II.C.3
12	VIII.D	I.B.5.b.(6)
13	NA	NA
-	III	Attachment A, Section XVIII
-	IV	IV.B
-	VI	I.B.5.b
Minor revision # 1000750		**Title V #1000102, Attachment B references**
I.A		This condition is not based on an applicable requirement, and so was not included in the Title V permit
I.B		I.N.2

<table>
<tr><th>IP #1156 references</th><th>Operating Permit #0375-96 references</th><th>Title V #1000102, Attachment B references</th></tr>
<tr><td colspan="2">I.C</td><td>I.N.1</td></tr>
<tr><td colspan="2">I.D</td><td>I.N.3</td></tr>
<tr><td colspan="2">II.A</td><td>III.L.2</td></tr>
<tr><td colspan="2">II.B</td><td>II.L.1</td></tr>
</table>

Note on IP Conditions 2 : This condition was no longer required after OP 0375-96 was issued.

Note on IP Condition 4 : The sulfur dioxide emissions resulting from coal combustion are directly related to the sulfur content of the coal. To maintain the same level of stringency as the installation permit, this condition has been retained.

Note on IP Condition 5 : This condition establishes the emissions standards for various pollutants. These conditions have been carried over. A particulate matter standard is not explicitly mentioned in the installation permit. The operating permit imposes a particulate standard. This is the same standard as in R18-2-703.C.1. The installation permit mentions an opacity limit of 20%.

Note on IP Condition 6 : This condition requires the installation of continuous monitoring systems to measure opacity, SOx, NOx and a diluent, in accordance with R18-2-313.. The operating permit clarifies that the CEMs need be used only when the unit is firing coal or fuel oil. There is no reference to R18-2-313 in the operating permit which only refers to the performance specifications of 40 CFR Part 60, Appendix B. The Title V permit carries over the requirement to operate CEMs when coal or fuel oil are burned. As far as QA/QC procedures are concerned, the Title V permit prescribes 40 CFR 75 methodologies. These are the most stringent procedures, and more than adequately meet the installation permit conditions.

Note on IP Condition 8 : The installation permit does not specifically require the installation of baghouses on Unit I4 boiler, or on the coal handling system units. This condition only requires that baghouses be maintained in good condition. OP #375-96 does require that a baghouse be installed on Unit I4 boiler. The source has been operating a baghouse, and this requirement is carried over into the Title V permit. The source has also been operating baghouses on the coal handling system. A requirement to operate baghouses has been written into the Title V permit. A requirement to maintain the baghouses in good operating condition has been written into the Title V permit.

Note on IP Condition 9 : This condition requires a TSP monitor for the purposes of monitoring fugitive emissions during the **construction phase** of the coal conversion project and fugitive coal and flyash emissions. This condition does not appear in OP 0375-96, and so was not included in the Title V permit.

Note on IP 1156 Condition 12: This condition states that alternate fuels **cannot** be fired simultaneously. The equivalent OP 0375-96 VIII.D condition states that alternate fuels shall not be fired simultaneously unless the continuous monitoring systems are operating. The latter version was included in the Title V permit.

Note on OP 0375-96 Condition VI : This condition prohibits the combustion of used oil. This specific prohibition is redundant and was left out of the Title V permit. Condition I.B.5.b lists the various fuels that the Permittee is **allowed** to burn.

<u>Pima County Operating Permit # 1052</u>

IP 1156 and OP 0375-96 were issued to cover operation of Unit I4 and the coal handling system. Pima County permit #1052 covered operation of the rest of the facility. These permit requirements include Pima County SIP rules. The rules, applicable facility wide, are (1) Opacity < 40%; and (2) Particulates $E < 1.02\ Q^{0.769}$. These requirements can be found in the Pima County SIP: (i) Regulation 32, Rule 321, and (ii) Regulation 33. The State Rule requirements that are in the Title V permit are equivalent to these rules. See Table V.2.

VII. PERIODIC MONITORING

A. Units I1, I2, and I3 Boilers

Opacity: Natural gas combustion results in minimal visible emissions. Prescribing a rigorous monitoring schedule would be impractical and would have no environmental benefit.

The Permittee may burn fuel oil in the boilers. Burning fuel oil may result in visible emissions of significant opacity. Therefore a structured monitoring plan has been prescribed. The Permittee is required to conduct weekly Method 9 observations.

Particulate: As illustrated in Table III.1 of this document, natural gas combustion results in low particulate emissions. The potential to emit is about 2% of the allowable emission rate, and the actual emissions data (from EI for the year 1996) is even lower. Therefore, burning pipeline quality natural gas assures continuous compliance with the particulate standard.

Fuel oil combustion results in particulate emissions that are higher than natural gas combustion. However, the potential to emit is still only 35% of the allowable emission standard. The Permittee has not burned fuel oil in recent times. Burning #6 fuel oil will assure compliance with the emission standard. Permittee is required to keep on record a copy of the contractual agreement. Although ash content by itself is not a valid measure of particulate matter emissions, monitoring this would help the agency to "ballpark" the particulate matter emissions.

Sulfur dioxide: The only applicable requirements for sulfur dioxide emissions when burning natural gas are those required by the Acid Rain (Title IV) program, as such, the only monitoring requirements are those required by the Acid Rain program.

When burning fuel oil, Permittee is required to demonstrate compliance with the A.A.C. R18-2-703.E.1 standard through calculations using the following equation :

SO2 (lb/MMBtu) = 2.0 x [(Weight percent of sulfur/100) x Density (lb/gal)]/[(Heating value (Btu/gal)) x (1 MMBtu/1,000,000 Btu)]

Hours of Operation: Permittee is required to keep track of the hours of operation till the performance tests are triggered.

B. Unit I4 Boiler

Opacity: The principal fuel used in this unit is coal. Installation Permit #1156 requires the use of a continuous opacity monitor. The Permittee need not operate the continuous opacity monitor while burning natural gas. However, the Permittee is required to continue operating the monitor during the transition period. There may be a possibility for residual particulate matter in the ducts to exit the stack even after the fuel switch is complete. Therefore, the Permittee is required to continue operation of the monitor until the opacity levels stabilize at levels representative of normal natural gas combustion.

Particulate: Table III.1 compares the PTE, allowable emissions, test data, and actual emissions for this unit. The uncontrolled particulate emissions while burning coal are very high. Proper maintenance and operation of the baghouse is key to meeting the standard. This permit requires the Permittee to perform a stack test every year plus periodically monitoring stack opacity to fulfill the periodic monitoring requirements for particulate matter emissions. Although no data is available to directly correlate opacity to particulate matter emissions, doing so would at least indicate potential problems with the air pollution control device. If corrective actions are taken to rectify the problems associated with the pollution control device, then compliance can be inferred on the basis that the source operates its pollution control equipment in a manner consistent with good air pollution control practices. The source proposed a 24-hr rolling average opacity of 15% beyond which corrective actions need to be investigated. The opacity limit is 20% for this source. Opacity above 15% but less than 20% does not hold the source in violation of the particulate matter standard, but merely requires the source to identify and alleviate the problem by taking corrective actions if necessary to reduce the opacity to less than 15%. However, not taking corrective actions if problems with the pollution control equipment are found could potentially hold the source in violation of the permit terms. Permittee is required to record the results of the investigation and the corrective actions taken, if any, and the date & time on which the action was taken.

As illustrated in Table III.1 of this document, natural gas combustion results in low particulate emissions. The potential to emit is about 2% of the allowable emission rate, and the actual emissions data (from EI for the year 1996) is even lower. Therefore, burning pipeline quality natural gas assures continuous compliance with the particulate standard.

Fuel oil combustion results in particulate emissions that are higher than for natural gas combustion. However, the potential to emit is still only 35% of the allowable emission standard. The Permittee has not burned fuel oil in recent times. Burning #6 fuel oil will assure compliance with the emission standard. Permittee is required to keep on record a copy of the contractual agreement. Although ash content by itself is not a valid measure of particulate matter emissions, monitoring this would help the agency to "ballpark" the particulate matter emissions. No engineering estimation using ash content is prescribed in the permit since it could be interpreted to incorrectly correlate particulate matter emissions to ash content only.

Sulfur dioxide: Installation Permit #1156 requires Permittee to maintain and operate a continuous emissions monitor for sulfur dioxide.

Nitrogen oxides: Installation Permit #1156 requires Permittee to maintain and operate a continuous emissions monitor for nitrogen oxides.

Hours of Operation: Permittee is required to keep track of the hours of operation till the performance tests are triggered.

CEM availability: AAC R18-2-313 does not contain specifications on CEM "availability", i.e, periods of monitor operation without downtime. Past performance indicates that the monitors are generally available for about 90% of operating time.

C. *Units IGT1, IGT2, IGT3 : Gas Turbines*

Opacity: Natural gas combustion results in minimal visible emissions. Prescribing a rigorous monitoring schedule would be impractical and would have no environmental benefit.

The Permittee may burn fuel oil in the gas turbines. Burning fuel oil may result in visible emissions of significant opacity. Therefore a structured monitoring plan has been prescribed. The Permittee is required to conduct a weekly Method 9 observation.

Particulate: As illustrated in Table III.1 of this document, natural gas combustion results in low particulate emissions. The potential to emit is about 7% of the allowable emission rate. Therefore, burning pipeline quality natural gas assures continuous compliance with the particulate standard.

Fuel oil combustion results in particulate emissions that are higher than natural gas combustion. However, the potential to emit is still only 15% of the allowable emission standard. The Permittee has not burned fuel oil in recent times. Burning #2 distillate fuel oil will assure compliance with the emission standard. Permittee is required to keep on record a copy of the contractual agreement. Although ash content by itself is not a valid measure of particulate matter emissions, monitoring this would help the agency to "ballpark" the particulate matter emissions.

Sulfur dioxide: Firing "pipeline quality" natural gas results in compliance with the standard. Therefore, the monitoring requirement is minimal.

When burning fuel oil, Permittee is required to maintain on record calculations that demonstrate compliance with the allowable emission limit using the following equation:

SO2 (lb/MMBtu) = 2.0 x [(Weight percent of sulfur/100) x Density (lb/gal)]/[(Heating value (Btu/gal)) x (1 MMBtu/1,000,000 Btu)]

Hours of Operation: Permittee is required to keep track of the hours of operation till the performance tests are triggered.

D. Coal Preparation Plant

Opacity The coal preparation plant is subject to the 40% opacity standard. The Permittee is required to make a weekly survey of the visible emissions from the entire coal plant including all the enclosed transfer points, the exposed transfer points, the storage pile, and the baghouses in the coal handling system. The Permittee is required to create a record of the date on which the visual survey was performed, the name of the observer, and the results of the survey. If the visible emission do not appear to exceed the standard, the Permittee would note in the record that the visible emissions were of low opacity, and it was not required to perform a Method 9.

If the Permittee finds that on an instantaneous basis the visible emissions could be in excess of 40% opacity, then he is required to make a six-minute Method 9 observation. If this observation indicates opacity in excess of 40% then the permittee is required to report it as excess emissions.

If the Permittee finds that the visible emissions are less than 40% opacity, then the Permittee is required to record the source of emission, date, time, and result of the test.

PM — The source is subject to the particulate matter standard in PCC 17.16.310. The permittee is required to maintain and operate the baghouses in accordance with best management practices. Permittee is also required to hold these specifications on file. Emissions related maintenance work needs to be recorded.

E. Fly Ash Handling

Same as Coal Preparation Plant

F. Open Areas etc.

The standards in Article 6 are applicable requirements for non-point sources. The following sources will be monitored:

1. Driveways, parking areas, vacant lots
2. Open areas (Used, altered, repaired, etc.)
3. Construction of roadways
4. Material transportation
5. Material handling
6. Storage piles
7. Stacking and reclaiming machinery at storage piles

All of these areas must comply with the opacity limitation of 40%. The Permittee is required to minimize emissions of particulate matter from these sources by the use of control measures such as weting agents, watering, covering, paving, barring access etc. The Permitee is required to keep track of the kind of control measure used. In addition to the 40 % opacity rule, Pima County SIP Rule 343 requires that "visible emissions" should not leave the property of the boundary. The practical enforceability of this rule has been debated over the past years. There have been instances in the past where the 40% opacity level served as the trigger for non-compliance investigations. However, there is no existing written policy on how the rule is to be interpreted, and enforcement decisions will likely be made on a case-by-case basis.

G. Other Periodic Activities

1. Open Burning

The Permittee has indicated in the application, that rare instances of open burning may occur. The condition in the permit directs the Permittee to obtain a permit from ADEQ, or the local officer in charge of issuing burn permits. Monitoring requirements for the applicable open burning rule may be satisfied by keeping all open burn permits on file.

2. Abrasive Sand Blasting

The Permittee has indicated in the permit application that there might be a few occasions on which abrasive sand blasting activities are conducted on-site. R18-2-726 and R18-2-702 (B) are applicable requirements, and as such have to be included in the permit. It was decided to prescribe minimal monitoring requirements.

3. Spray Painting

The Permittee has indicated in the permit application that there might be a few occasions on which spray painting activities are conducted on-site. R18-2-727 and R18-2-702(B) are applicable requirements, and as such, have to be included in the permit. R18-2-727(A) and R18-2-727(B) are included in the approved State Implementation Plan (SIP). R18-2-727(C) and R18-2-727(D) are also a part of the approved SIP. They are present in the definitions section of the SIP as R9-3-101.117. EPA approved SIP provision R9-3-527.C is not present in the amended rule. However, R9-3-527.C is an applicable requirement, and is federally enforceable till the current State SIP is approved by the EPA. It was decided to prescribe minimal monitoring requirements.

4. Mobile Sources, Demolition/Renovation, Nonvehicle Airconditioner Maintenance

It was decided to prescribe minimal monitoring requirements.

VIII. TESTING REQUIREMENTS

Testing requirements have been included in the permit as a periodic monitoring measure.

Unit I1, Unit I2, Unit I3 Boilers

Sulfur Dioxide: When liquid fuel is burned as the main fuel on an annual basis, Permittee is required to perform an annual performance test to demonstrate compliance with the standard. The permit condition defines what constitutes a "main" fuel. 40 CFR 72.2 (*Oil-fired*) defines what oil-fired units are for the purposes of the Acid Rain Program. This definition was borrowed to identify a "main fuel" in an enforceable manner. The definition indicates that a unit using fuel oil for greater than 15% of the annual heat input would be considered an oil-fired unit. Units I1, I2, and I3 are used on a periodic basis. There may conceivably be a situation where one of these units is used for only 1000 hours during a year. If the strict definition of 40 CFR 72.2 were to be followed, then the unit would have to be tested if it used fuel oil for 15% of 1000 hours, i.e. 150 hours. This is a stringent requirement. To avoid such a situation, an hour limit was derived based on the 15% usage, and the potential maximum number of hours (8760 on an annual basis). This threshold point is : 0.15 * 8760 ~~ 1300 hours on an annual basis.

Nitrogen Oxides: There is no applicable requirement for nitrogen oxides emissions. Units I1 and I2 use continuous emission monitors (for Acid Rain) and emissions data for these units is available. Unit I3 is currently classified as a "peaking unit" and therefore does not require emission monitors. If the Unit I3 were to be operated on a more frequent basis, it would lose its peaking unit status, and would be required to install an emissions monitor for Acid Rain purposes. In the time that it takes the source to install the emissions monitor, if the emissions were to exceed 100 tpy, a performance test is required for the reasons outlined in the following section on testing for Carbon Monoxide.

Carbon Monoxide — There is no applicable standard for carbon monoxide emissions. However, the PTE for CO is greater than 100 tpy. Although there is no applicable standard for carbon monoxide, the Permittee is required to test each unit for conventional air pollutants that are emitted in quantities above 100 tons in a year. The reasons for this test are as follows:

1. the test will have a direct impact on the annual emission fee;
2. the test will be the basis for any future modification; and
3. the test will help to get a clearer picture of the actual emissions from major sources in Arizona. While emission factors play an important role in the air pollution control program, they do not yield reliable data unless they are either developed directly from the emission unit in question or substitutes for a proven mass-balance relationship. Thus, testing would provide valuable information.

   Emissions calculations were performed to determine the number of hours of operation that would result in the emissions of 100 tons of pollutant. For example, for Unit I1, the rate of CO emission while burning liquid fuel is 32 lb/hr (see application form). The number of hours that would result in a 100 ton emission can be calculated from the following equation :

   (32 lb/hr) * H hours * (1 ton/2000lb) < = 100 tons

   H = 6250 hours

   Other hour values were derived in a similar fashion.

Unit I4 Boiler

An annual performance test has to be performed on Visible Emissions, PM, SO_x, and NO_x. The annual performance tests are required to demonstrate compliance with the standards. The installed continuous emissions monitors are for periodic monitoring purposes only.

For Carbon Monoxide, a testing schedule has been derived based on the considerations discussed in the paragraph on carbon monoxide emissions from Units I1, I2, and I3 boilers.

Units IGT1, IGT2, IGT3

Sulfur Dioxide — When liquid fuel is burned as the main fuel on an annual basis, Permittee is required to perform an annual performance test to demonstrate compliance with the standard. The permit condition defines what constitutes a “main” fuel. 40 CFR 72.2 (*Oil-fired*) defines what oil-fired units are for the purposes of the Acid Rain Program. This definition was borrowed to identify a “main fuel” in an enforceable manner. The definition indicates that a unit using fuel oil for greater than 15% of the annual heat input would be considered an oil-fired unit. Units I1, I2, and I3 are used on a periodic basis. There may conceivably be a situation where one of these units is used for only 1000 hours during a year. If the strict definition of 40 CFR 72.2 were to be followed, then the unit would have to be tested if it used fuel oil for 15% of 1000 hours, i.e. 150 hours. This is a stringent requirement. To avoid such a situation, an hour limit was derived based on the 15% usage, and the potential maximum number of hours (8760 on an annual basis). This threshold point is : 0.15 * 8760 ~~ 1300 hours on an annual basis.

Nitrogen Oxides	Testing schedules have been derived for the various pollutants based on their potential
Carbon Monoxide	to emit greater than 100 tons of pollutant in a 12 month period.

Cooling Towers

It is infeasible to conduct a performance test on particulate matter emissions from cooling towers because of the impracticality and asscoiated costs. Engineering calculations will be used as periodic monitoring for the particulate standards.

Flyash Handling

As indicated by the emissions inventory information, the actual emissions from the fly ash handling stacks are very low. The prescribed periodic monitoring of control equipment performance is sufficient to demonstrate that emissions are below the standard during normal operations. Therefore, testing is not being required in the permit.

IX. INSIGNIFICANT ACTIVITIES

The applicant has requested the following activities to be deemed as "insignificant". According to A.A.C. R18-2-101.54, for an activity to be deemed "insignificant", there should be no applicable requirement for the activity. This was the basis used to determine if the activities in the following list qualify as an "insignificant" activity under Arizona law.

S. No.	ID	INSIGNIFICANT ACTIVITY NAME	Yes/No	Reason
1	C1	Power Production - Unpaved Access Road	No	Article 6
2	C21	Power Production - Rotary Car Dumper Latrine Vent/Septic System	Yes	AACR18-2-101.54 (j)
3	C22	Power Production - Crusher Tower Latrine Vent/Septic System	Yes	AACR18-2-101.54 (j)
4	FH9	Power Production - Condensate Return Collection Sump Vents	Yes	AACR18-2-101.54 (j)
5	FH10	Power Production - Fuel Oil Unloading/Transfer/Pumping and Piping Facilities	Yes	AACR18-2-101.54 (j)
6	FH11	Power Production - Waste Oil Drums	Yes	AACR18-2-101.54 (j)
7	A6	Power Production - Flyash Latrine Vents	Yes	AACR18-2-101.54 (j)
8	CHEM1	Power Production - North 12,000 gal 93% Sulfuric Acid Storage Tank	Yes	AACR18-2-101.54 (j)

S. No.	ID	INSIGNIFICANT ACTIVITY NAME	Yes/No	Reason
9	CHEM2	Power Production - North 12,000 gal 50% Liquid NaOH Storage Tank	Yes	AACR18-2-101.54 (j)
10	CHEM3	Power Production - North Water Treatment Chemical Storage Bins/Barrels	Yes	AACR18-2-101.54 (j)
11	CHEM4	Power Production - North Cooling Tower Treatment Room	Yes	AACR18-2-101.54 (j)
12	CHEM5	Power Production - North Boiler Water Treatment Area	Yes	AACR18-2-101.54 (j)
13	CHEM6	Power Production - South 12,000 gal 93% Sulfuric Acid Storage Tank	Yes	AACR18-2-101.54 (j)
14	CHEM7	Power Production - South Water Treatment Chemical Storage Bins/Barrels	Yes	AACR18-2-101.54 (j)
15	CHEM8	Power Production - South Cooling Tower Treatment Room	Yes	AACR18-2-101.54 (j)
16	CHEM9	Power Production - South Boiler Water Treatment Area	Yes	AACR18-2-101.54 (j)
17	CHEM10	Power Production - Demineralizer Vacuum Degasifier (2)	Yes	AACR18-2-101.54 (j)
18	CHEM11	Power Production - Coal Laboratory Latrine Vent/Septic System	Yes	AACR18-2-101.54 (j)
19	CHEM12	Power Production - Fume Hood	Yes	AACR18-2-101.54 (j)
20	CHEM13	Power Production - Water Laboratory Fume Hood	Yes	AACR18-2-101.54 (j)
21	CHEM14	Power Production Coal Laboratory Heater	Yes	AACR18-2-101.54 (j)
22	CHEM15	Power Production - Boiler Feedwater Storage Tanks (6)	Yes	AACR18-2-101.54 (j)
23	WW1	Power Production - North Clooection Sump-Boiler Blowdown, Demineralizer Regenerant	Yes	AACR18-2-101.54 (j)
24	WW2	Power Production - South Collection Sump (2) - Rain Runoff, Ash/Coal Area Washdown	Yes	AACR18-2-101.54 (j)
25	WW3	Power Production - Bottom Ash Runoff Collection Sump	Yes	AACR18-2-101.54 (j)
26	WW4	Power Production - Plant Waste Basin-Bopiler Blowdown, Demineralizer Regenerant	Yes	AACR18-2-101.54 (j)
27	WW5	Power Production - Coal Pile Runof Basin- Rain Runoff, Ash/Coal Area Washdown	Yes	AACR18-2-101.54 (j)

S. No.	ID	INSIGNIFICANT ACTIVITY NAME	Yes/No	Reason
28	WW6	Power Production - Evaporation Basin (3) - Treated Wastewater from Plant Waste/Coal Pile Runoff Basin	Yes	AACR18-2-101.54 (j)
29	WW7	Power Production - Waste Water Treatment Latrine Vent/Septic System	Yes	AACR18-2-101.54 (j)
30	WW8	Power Production - Waste Water Treatment 5,000 gal 93% Sulfuric Acid Tank	Yes	AACR18-2-101.54 (j)
31	WW9	Power Production - Waste Water Treatment 5,000 gal 50% Liquid NaOH Tank	Yes	AACR18-2-101.54 (j)
32	WW10	Power Production - Waste Water Treatment Clarifier - Wastewater 140,000 gal	Yes	AACR18-2-101.54 (j)
33	WW11	Power Production - Waste Water Treatment Scum Tank- Clarifier Scum for recycle 1170 gal	Yes	AACR18-2-101.54 (j)
34	WW12	Power Production - Waste Water Treatment pH Adjustment Tank- Pretreated Wastewater 6768 gal	Yes	AACR18-2-101.54 (j)
35	WW13	Power Production - Waste Water Treatment pH Adjustment Tank- Treated Wastewater 5000 gal	Yes	AACR18-2-101.54 (j)
36	WW14	Power Production - Waste Water Treatment Chemical Mix Tank (2) - Alum 730 gal	Yes	AACR18-2-101.54 (j)
37	WW15	Power Production - Waste Water Treatment Chemical Mix Tank (2) - Polymer 148 gal	Yes	AACR18-2-101.54 (j)
38	I1A	Power Production - Unit #1 Boiler Blowdown Flashtank	Yes	AACR18-2-101.54 (j)
39	I1F	Power Production - North Turbine Lube Oil Storage Tank	Yes	AACR18-2-101.54 (j)
40	I1G	Power Production - Unit #1 Fuel Gas Piping	Yes	AACR18-2-101.54 (j)
41	I1H	Power Production - Unit #1 Fuel Gas Vents	Yes	AACR18-2-101.54 (j)
42	I1I	Power Production - Unit #1 Boiler Safety Relief Valve Vents	Yes	AACR18-2-101.54 (j)
43	I1J	Power Production - Unit #1 Steam/Drain Vents	Yes	AACR18-2-101.54 (j)
44	I1K	Power Production - Unit #1 Main Transformer	Yes	AACR18-2-101.54 (j)
45	I1L	Power Production - Unit #1 Auxiliary Transformer	Yes	AACR18-2-101.54 (j)
46	I2A	Power Production - Unit #2 Boiler Blowdown Flashtank	Yes	AACR18-2-101.54 (j)

S. No.	ID	INSIGNIFICANT ACTIVITY NAME	Yes/No	Reason
47	I2E	Power Production - Unit #2 Fuel Gas Piping	Yes	AACR18-2-101.54 (j)
48	I2F	Power Production - Unit #2 Fuel Gas Vents	Yes	AACR18-2-101.54 (j)
49	I2G	Power Production - Unit #2 Boiler Safety Relief Valve Vents	Yes	AACR18-2-101.54 (j)
50	I2H	Power Production - Unit #2 Steam/Drain Vents	Yes	AACR18-2-101.54 (j)
51	I2I	Power Production - Unit #2 Main Transformer	Yes	AACR18-2-101.54 (j)
52	I2J	Power Production - Unit #2 Auxiliary Transformer	Yes	AACR18-2-101.54 (j)
53	I3A	Power Production - Unit #3 Boiler Blowdown Flashtank	Yes	AACR18-2-101.54 (j)
54	I3E	Power Production - South Turbine Lube Oil Storage Tank	Yes	AACR18-2-101.54 (j)
55	I3F	Power Production - Unit #3 Fuel Gas Piping	Yes	AACR18-2-101.54 (j)
56	I3G	Power Production - Unit #3 Fuel Gas Vents	Yes	AACR18-2-101.54 (j)
57	I3H	Power Production - Unit #3 Boiler Safety Relief Valve Vents	Yes	AACR18-2-101.54 (j)
58	I3I	Power Production - Unit #3 Steam/Drain Vents	Yes	AACR18-2-101.54 (j)
59	I3J	Power Production - Unit #3 Main Transformer	Yes	AACR18-2-101.54 (j)
60	I3K	Power Production - Unit #3 Auxiliary Transformer	Yes	AACR18-2-101.54 (j)
61	I4A	Power Production - Unit #4 Boiler Blowdown Flashtank	Yes	AACR18-2-101.54 (j)
62	I4F	Power Production - Unit #4 Fuel Gas Piping	Yes	AACR18-2-101.54 (j)
63	I4G	Power Production - Unit #4 Fuel Gas Vents	Yes	AACR18-2-101.54 (j)
64	I4H	Power Production - Unit #4 Boiler Safety Relief Valve Vents	Yes	AACR18-2-101.54 (j)
65	I4I	Power Production - Unit #4 Steam/Drain Vents	Yes	AACR18-2-101.54 (j)

S. No.	ID	INSIGNIFICANT ACTIVITY NAME	Yes/No	Reason
66	I4J	Power Production - Unit #4 Main Transformer	Yes	AACR18-2-101.54 (j)
67	I4K	Power Production - Unit #4 Auxiliary Transformer	Yes	AACR18-2-101.54 (j)
68	I5	Power Production - Power Block Latrine Vents	Yes	AACR18-2-101.54 (j)
69	I6	Power Production - Engineering Building Latrine Vents	Yes	AACR18-2-101.54 (j)
70	I7	Power Production - Power Block Used Oil Storage Drums	Yes	AACR18-2-101.54 (j)
71	I8	Power Production - Power Block Battery Rooms	Yes	AACR18-2-101.54 (j)
72	I9	Power Production - Common Facilitites Battery Room	Yes	AACR18-2-101.54 (j)
73	I11	Power Production - Mechanical Maintenance Flammable Storage cabinets	Yes	AACR18-2-101.54 (j)
74	I12	Power Production - Switchyard Circuit Breakers/Transformers	Yes	AACR18-2-101.54 (j)
75	I14	Power Production - Maintenance Shop Welding Activities/Vents	Yes	AACR18-2-101.54 (j)
76	I16	Power Production - 2nd Floor Change Room Heater	No	AACR18-2-724
77	I17	Power Production - 2nd Floor Change Room Water Heater	No	AACR18-2-724
78	I18	Power Production - 3rd Floor Conference Room Heater	No	AACR18-2-724
79	I19	Power Production - 3rd Floor Classroom Heater	No	AACR18-2-724
80	I20	Power Production - Control Room #1 Heater	No	AACR18-2-724
81	I21	Power Production - Control Room #2 Heater	No	AACR18-2-724
82	I72	Power Production - #5 Fire/Dust Control Water Storage Tank 3,000,000 gal	Yes	AACR18-2-101.54 (j)
83	I73	Power Production - Service Water Pressure/Storage Tank 150,000 gallons	Yes	AACR18-2-101.54 (j)
84	SS1	Servicenter - HVAC Cooling Tower	Yes	AACR18-2-101.54 (j)
85	SS2	Servicenter - Reproduction Equipment	Yes	AACR18-2-101.54 (j)
86	SS4	Servicenter - Latrine Vents	Yes	AACR18-2-101.54 (j)

S. No.	ID	INSIGNIFICANT ACTIVITY NAME	Yes/No	Reason
87	WH1	Warehouse - Water Heater 33.5 kBTU	No	AACR18-2-724
88	WH2	Warehouse - Furnace York 200 kBTU	No	AACR18-2-724
89	WH3	Warehouse - Furnace York 120 kBTU	No	AACR18-2-724
90	WH4	Warehouse - Latrine Vents	Yes	AACR18-2-101.54 (j)
91	GS1	General Shop - Suspended Heater 125 kBTU	No	AACR18-2-724
92	GS2	General Shop - Suspended Heater 50 kBTU	No	AACR18-2-724
93	GS3	General Shop - Suspended Heater 50 kBTU	No	AACR18-2-724
94	GS4	General Shop - Suspended Heater 50 kBTU	No	AACR18-2-724
95	GS5	General Shop - Suspended Heater 50 kBTU	No	AACR18-2-724
96	GS6	General Shop - Suspended Heater 50 kBTU	No	AACR18-2-724
97	GS7	General Shop - Suspended Heater 50 kBTU	No	AACR18-2-724
98	GS8	General Shop - Water Heater 32 kBTU	No	AACR18-2-724
99	GS9	General Shop - Furnace 75 kBTU	Yes	AACR18-2-101.54 (j)
100	GS10	General Shop - Latrine Vents	Yes	AACR18-2-101.54 (j)
101	TRAN1	Transportation - New/Used Lubricating Oil Storage	Yes	AACR18-2-101.54 (j)
102	TRAN2	Transportation - Underground Diesel Storage 15,000 gal	Yes	AACR18-2-101.54 (j)
103	TRAN4	Transportation - Water Heater 40 kBTU	No	AACR18-2-724
104	TRAN5	Transportation - Furnace York 200 kBTU	No	AACR18-2-724
105	TRAN6	Transportation - Suspended Heater 50 kBTU	No	AACR18-2-724
106	TRAN7	Transportation - Suspended Heater 50 kBTU	No	AACR18-2-724
107	TRAN8	Transportation - Suspended Heater 50 kBTU	No	AACR18-2-724
108	TRAN9	Transportation - Suspended Heater 250 kBTU	No	AACR18-2-724
109	TRAN10	Transportation - Suspended Heater 250 kBTU	No	AACR18-2-724
110	TRAN11	Transportation - Suspended Heater 225 kBTU	No	AACR18-2-724
111	TRAN12	Transportation - Suspended Heater 225 kBTU	No	AACR18-2-724
112	TRAN13	Transportation - Latrine Vents	Yes	AACR18-2-101.54 (j)

S. No.	ID	INSIGNIFICANT ACTIVITY NAME	Yes/No	Reason
113	OH1	Operating Headquarters - HVAC Cooling Tower	Yes	AACR18-2-101.54 (j)
114	OH4	Operating Headquarters - Latrine Vents	Yes	AACR18-2-101.54 (j)
115	OH5	Operating Headquarters - Training Center Latrine Vents	Yes	AACR18-2-101.54 (j)
116	OH6	Operating Headquarters - Trailer Latrine Vents	Yes	AACR18-2-101.54 (j)
117	FH1	Fuel Oil Storage Tank #1	Yes	AACR18-2-101.54 (j)
118	FH2	Fuel Oil Storage Tank #2	Yes	AACR18-2-101.54 (j)
119	FH3	Fuel Oil Storage Tank #3	Yes	AACR18-2-101.54 (j)
120	FH6	Fuel Oil Storage Tank #6	Yes	AACR18-2-101.54 (j)
121	FH7	Fuel Oil Storage Tank #7	Yes	AACR18-2-101.54 (j)
122	FH8	Fuel Oil Storage Tank #8	Yes	AACR18-2-101.54 (j)
123	FH9	Fuel Oil Storage Tank #9	Yes	AACR18-2-101.54 (j)
124	FH10	Fuel Oil Storage Tank #10	Yes	AACR18-2-101.54 (j)